

334 **Q. How do you plan to administer the requirement that customers within**  
335 **Service Classification BGS-2 remain at demand levels less than 150**  
336 **kilowatts?**

337 A. The Ameren Companies will install a “check” demand meter on any customer  
338 within Service Classification BGS-2 whenever the customer’s monthly kilowatt-  
339 hours exceed 37,000 kilowatt hours. This level equates to a load factor of  
340 approximately 34%, noticeably lower than the class average of approximately  
341 50%. If the “check” meter registers a demand equal to or greater than 150  
342 kilowatts, then the customer will be moved to Service Classification BGS-3 for a  
343 minimum term of one year, unless the customer opts for the RTP rate.

344 **Q. Please describe further Service Classification BGS-3 – General Service.**

345 A. Service Classification BGS-3 will apply to all customers with individual metered  
346 demands ranging from 150 kilowatts to less than 1,000 kilowatts and who elect  
347 full requirements power service from the Ameren Companies and who satisfy all  
348 of the other applicable requirements for Intermediate Service of the Delivery  
349 Service (DS-3) tariff. Customers within this classification will require Time of  
350 Day (“TOD”) energy and demand metering and basic charges for BGS service in  
351 this classification are TOD energy with seasonal differentiation.

352 **Q. Please describe Service Classification BGS-4 – Large Service.**

353 A. Service Classification BGS-4 - Large Service will apply to all customers with  
354 individual metered demands of at least 1,000 kilowatts and who elect full  
355 requirements service from one of the Companies during an “Open Enrollment  
356 Period,” and who satisfy all other applicable requirements for Large Service (DS-

357 Rate 4). Customers within this classification will require hourly load profile  
358 energy and demand metering and basic charges for BGS service in this  
359 classification are TOD energy with seasonal differentiation.

360 **Q. Please describe the “Open Enrollment Period” for this service.**

361 A. As described in the testimony of Mr. Blessing, within 30 days of the results of the  
362 auction, DS-4 customers may opt for a one year commitment for power service  
363 under BGS-4. Customers electing this option must provide the Ameren  
364 Companies with a “wet” signature to verify the selection of BGS-4 for power  
365 service.

366 **Q. Please describe Service Classification BGS-5 – Dusk to Dawn Lighting**  
367 **Service.**

368 A. Service Classification BGS-5 – Dusk to Dawn Lighting Service will apply to all  
369 un-metered outdoor dusk to dawn lighting service automatically controlled by  
370 electronic photocells and who elect full requirements power service from the  
371 Company and who satisfy all other applicable requirements for either Private  
372 Outdoor Area Lighting (DS-5) or Municipal Outdoor Lighting (DS-6) Service.  
373 The Ameren Companies have established a separate classification for this type of  
374 lighting service to recognize the unique load characteristics of photocell  
375 controlled lighting. Over the years, the Ameren Companies have compiled data  
376 that yields the determination of the hours of operation by month for the  
377 predictable and “constant” load of photocell controlled lights and, therefore, from  
378 a cost causation and equitable cost recovery perspective, it was logical to create a  
379 class consisting solely of photocell controlled outdoor area lighting. The loads of

380 non lighting customer classes are not nearly as predictable or constant, thereby  
381 further supporting the need for a separate rate class.

382 **III. RATE TRANSLATION DISCUSSION**

383 **Q. With regard to the fixed price power product, you earlier stated that the**  
384 **auction process would produce a single clearing price for customers with**  
385 **individual demands less than 1,000 kilowatts and a separate single clearing**  
386 **price for customers with individual demands greater than 1,000 kilowatts.**

387 **How do you propose to translate these single winning bid prices from the**  
388 **auction processes into BGS rates for the respective customer groups?**

389 **A.** One of the simplest ways to pass these prices on to customers would be billing all  
390 energy of customers within these two fixed price products at the winning auction  
391 price for the respective product. While such a billing approach would recover the  
392 Ameren Companies' total costs of power via the bid or auction process, it would  
393 not do so in an equitable and cost-causative manner. To accomplish the recovery  
394 of these costs in an equitable and cost -causative manner, we have customized or  
395 tailored a "translation tool" or "prism" utilized in New Jersey to develop class  
396 rates for retail customers of Public Service Electric and Gas ("PSE&G").

397 **Q. Please explain.**

398 **A.** We are utilizing the underlying principles of the PSE&G tool, as adjusted to  
399 reflect Ameren Footprint and MISO specifics. The first step in the process is to  
400 develop, annually before each auction, class seasonal and/or TOD multiplicative  
401 factors. These multiplicative factors are developed from the Rate Translation  
402 Prism ("Prism"). The Prism combines forward market data for energy and

403 capacity with historical class load data, class historical sales, losses, and where  
404 applicable, class blocking data to develop BGS class load-weighted seasonal  
405 and/or TOD per unit costs and total system average load-weighted per unit cost.  
406 The resulting multiplicative factors are the ratios of the class load-weighted  
407 seasonal and/ or TOD per unit costs to the total system average load-weighted per  
408 unit cost. The Ameren Companies' "Prism" spreadsheets are attached as Resp.  
409 Exhibit 5.3.

410 The forward market data for energy and capacity, historical load data and class  
411 historical sales utilized in the Prism will be updated annually prior to each  
412 auction. Tables 1 – 16 of the Resp. Ex. 5.3 are the spreadsheets that produce the  
413 resulting multiplicative factors. Tables 1-13 are the same for each BGS service  
414 classification and Tables 14-16 are the same for each fixed price auction product.

415 **Q. Please explain Table No. 1 of Resp. Ex. 5.3.**

416 A. Table No. 1 contains input data representing the percentage of on-peak energy, by  
417 month, by each Ameren Company, and for each proposed rate schedule. The on-  
418 peak period as used in this table is defined as the 16 hour period from 6:00 a.m. to  
419 10:00 p.m. CPT, Monday through Friday. All remaining weekday hours and all  
420 hours on weekends and holidays recognized by the NERC are considered off-  
421 peak. For illustrative purposes, the values in this table for each month are the  
422 average on-peak percentages as calculated from the most recent load research data  
423 of the Ameren Companies. We are proposing to update this data annually xx  
424 business days prior to the first day of the auction. Subsequent annual revisions  
425 will utilize average peak usage percentages based on load profile data for the 24

426 consecutive monthly billing periods extending through the monthly period ending  
427 no later than five (5) months prior to the earliest possible auction commencement  
428 date. Utilizing a two (2) year period will reduce the variability of weather effects  
429 on the percentages from any single year. Should load profile data be unavailable  
430 for the 24 consecutive months prior to the initial auction, we will utilize the most  
431 recent 12 months of data.

432 **Q. Please explain Table No. 2 of Resp. Exhibit 5.3.**

433 A. Table 2 is a data input placeholder for percentage use during on-peak and off-  
434 peak periods that would be different from the 16 hour period discussed earlier in  
435 Table No. 1. Table 2 is necessary only if there is a need to use on-peak billing  
436 periods that differ significantly from those used for inputting of forward market  
437 prices, as discussed below. As stated earlier, the Ameren Companies' proposed  
438 on-peak billing hours are the same for the summer months and differ by one hour  
439 for the non-summer months. The slight shift of one hour during the non-summer  
440 months is not expected to have any material impact on the resultant pricing of the  
441 BGS services.

442 **Q. Please explain Table No. 3 of Resp. Exhibit 5.3.**

443 A. Table No. 3 is a data input table which contains the average energy usage in each  
444 monthly billing period based on energy delivered to each BGS service  
445 classification, as expanded for losses, for the Ameren Companies in the 24  
446 consecutive monthly billing periods extending through the monthly billing period  
447 ending no later than five (5) months prior to the earliest possible auction  
448 commencement date. For illustrative purposes, in this filing, Table No. 3 is

449 populated with historical calendar month sales of the Ameren Companies for the  
450 calendar year 2003, by month and by each proposed BGS rate classification at the  
451 bulk supply system level.

452 **Q. Please explain Table No. 4 of Resp. Exhibit 5.3.**

453 A. Table No. 4 contains the forwards prices for energy, by month and by time period  
454 (On-Peak and Off-Peak) corresponding to the applicable annual period for which  
455 retail supply charges are being determined. In this filing these forward prices are  
456 not necessarily the view of the Ameren Companies but, instead are meant to serve  
457 only as proxies to help facilitate or illustrate the results of the use of the Prism.  
458 We are proposing the following procedure for determining On-Peak and Off-Peak  
459 Energy Market Forwards prior to the initial auction and subsequent annual  
460 revisions.

461 A monthly Peak Energy Market Forward Price ( $PE_{mo}$ ) and monthly Off-Peak  
462 Energy Market Forward Price ( $OE_{mo}$ ) in dollars per megawatt-hour (\$/MWh), will  
463 be determined from the market data from forward contracts for electric power  
464 delivered into the MISO's Central Illinois Hub from 6:00 a.m. to 10:00 p.m.  
465 Monday through Friday, excluding NERC holidays. Should the MISO energy  
466 market be delayed or develop more slowly than anticipated, we will utilize the  
467 Into Cinergy Hub as an alternative source. A separate  $PE_{mo}$  and  $OE_{mo}$  will be  
468 determined for each relevant calendar month in the respective BGS rate period.  
469 The Ameren Companies will use the Intercontinental Exchange reporting service  
470 or Platt's Energy Trader as the source of the market data, but may include  
471 additional or different electronic exchanges or reporting services in the future as

472 allowed by the Commission. The market data will be obtained daily by the  
473 Companies from these sources' end-of-day reports to obtain a representation of  
474 the market for each of the forward contracts for the respective auction period.  
475 The market data will be obtained on each of the ten consecutive business days  
476 ending on or before the date ninety days prior to the earliest possible auction  
477 commencement date.

478 In the absence of market data for forward contracts with terms for individual  
479 months, market data for forward contracts with longer terms will be utilized. In  
480 the event no data exists for any given month in the off-peak period for which data  
481 is to be obtained, we will use ratios of actual off-peak to on-peak MISO locational  
482 marginal prices for the Ameren control areas for the most recent historical month  
483 corresponding to the month for which no forecast data exists. In the event that no  
484 data exists for any given month in the on-peak period for which data is to be  
485 obtained, we will use data for a more recent comparable month.

486 **Q. Please explain Table No. 5 of Resp. Exhibit 5.3.**

487 A. An adjustment of the forward prices contained in Table No. 4 must be corrected  
488 for the effects, if any, of transmission congestion on the MISO system between  
489 the MISO Central Illinois Hub and the Ameren zone where the BGS supply will  
490 be utilized. Table No. 5 contains an estimate of the average congestion factors,  
491 by month and by time period. Since the MISO system is in its infancy stages and  
492 thus has no useful history of such congestion, we have set this adjustment equal to  
493 "1" in this filing. The setting of this factor to "1" removes any consideration of  
494 congestion for this filing. We may, in subsequent annual revisions, include an

495 estimate of the average congestion factor should such congestion in the MISO  
496 system become a known quantity. Approval of a charge in the average congestion  
497 factor would be sought from the Commission.

498 **Q. Please explain Table No. 6 of Resp Exhibit 5.3.**

499 A. Table No. 6 contains, for each of the Ameren Companies, the factors utilized for  
500 average distribution system losses and unaccounted for supply by proposed BGS  
501 rate schedule with adjustments to reflect delivery voltages. Currently, the loss  
502 factors are those shown in each of the Ameren Companies' applicable Delivery  
503 Services tariffs. Such loss factors are multiplied by metered customer usage to  
504 calculate the expected metered consumption at the bulk system level. Of course,  
505 these loss factors may be updated or adjusted from time to time as approved by  
506 this Commission.

507 **Q. Please explain Table No. 7 of Resp. Exhibit 5.3.**

508 A. Table No. 7 is the calculation of, for each of the Ameren Companies, the energy-  
509 only per unit costs by proposed BGS rate, time period, and season. These values  
510 are the seasonal and time period average costs per MWh as measured at the bulk  
511 system based on monthly time period weights from Table No. 1 and forwards  
512 prices from Table No. 4 as corrected for congestion (Table No. 5). These average  
513 per unit costs do not include the costs associated with ancillary services,  
514 generation obligations or transmission costs, which will be considered in  
515 subsequent calculations.



516 **Q. Please explain Table No. 8 of Resp. Exhibit 5.3.**

517 A. Table No. 8 indicates, for the Ameren Companies, the total value of the average  
518 BGS energy-only costs, by proposed BGS rate classification, time period and  
519 season. These values are the results from multiplying the unit costs from Table  
520 No. 7, the monthly time period weights from Table No. 1 and the total sales to  
521 customers from Table No. 3. These seasonal and rating period costs are used in  
522 Table No. 9 to calculate per unit costs at the customer's meter.

523 **Q. Please explain Table No. 9 of Resp. Exhibit 5.3.**

524 A. Table No. 9 shows the resulting Ameren Companies' composite rate class load  
525 weighted seasonal and TOD per unit energy-only costs at the customer's meter  
526 and are used to develop the rate multipliers and seasonal payment factors  
527 discussed later in this testimony. These values result from dividing the sum of  
528 each of the Ameren Companies' average BGS energy-only seasonal, TOD and  
529 total costs from Table No. 8 by the composite applicable seasonal, TOD, or total  
530 MWh use at the customer's meter.

531 **Q. Please explain Table No. 10 of Resp. Exhibit 5.3.**

532 A. Table No. 10 sets up the data necessary for the inclusion of the costs of the  
533 generation and transmission obligations. The top portion of Table No. 10 shows,  
534 for each of the Ameren Companies, the total obligations by proposed BGS rate  
535 classification. Over the years, the Commission has approved the use of peak  
536 loads for the allocation of fixed costs associated with generation and transmission  
537 assets. As a result, we utilized the average of the four summer coincident peaks  
538 for each class to allocate similar market-based fixed costs in this filing. The use of

539 four coincident peaks does a fair job of recognizing the significant multiple peaks  
540 on the Companies' system. The middle portion of this table shows the number of  
541 summer and non-summer days and months that are used in this analysis. The  
542 bottom portion of this table shows the annual cost for transmission service and a  
543 seasonally differentiated market price of generation capacity. In this filing, the  
544 cost of transmission service is set to zero. It is our intent that the bid prices will  
545 exclude network transmission service and that these costs will be charged  
546 separately to retail customers through application of a new transmission cost  
547 recovery tariff that the Ameren Companies plan to file in their next DS rate  
548 filings. Currently, there is not a MISO capacity market in place; therefore, we are  
549 proposing to use an estimate of the current wholesale market prices for capacity in  
550 PJM as a proxy. The Ameren Companies will use MISO capacity market prices  
551 in the first filing of the Prism after such market exists.

552 **Q. Please explain Table No. 11 of Resp. Exhibit 5.3.**

553 A. Table No. 11 are the costs of ancillary transmission services to be included in the  
554 winning bid price. We proposes that ancillary services costs be based on  
555 averaging historical annual ancillary transmission services costs incurred in the  
556 provision of electric power supply for the 12 months ending no later than 90 days  
557 prior to the auction commencement date. Since there is no history of MISO  
558 ancillary costs, we have chosen, in this filing, to utilize the average \$ per MWh  
559 ancillary services cost as determined by PSE&G in the most recent PJM auction  
560 which is meant to serve only as a proxy to help facilitate and illustrate the results  
561 of the use of the Prism.

562 **Q. Please explain Table No. 12 of Resp. Exhibit 5.3.**

563 A. Table No. 12 shows the result of the allocation of both transmission and  
564 generation costs on a per MWh basis to the proposed BGS rate classifications.  
565 These values are the result of, for each proposed BGS rate, dividing the sum of:  
566 (1) each of the Ameren Companies' average four coincident peaks from the upper  
567 portion of Table No. 10, multiplied by (2) the seasonal daily capacity price,  
568 multiplied by (3) the number of days per the seasonal period per the middle  
569 portion of Table No. 10, by the sum of each of the Ameren Companies' seasonal  
570 MWh at the customers' meters.

571 **Q. Please explain Table No. 13 of Resp. Exhibit 5.3.**

572 A. Table No. 13 contains the overall supply cost computation by rate classification,  
573 by summer and non-summer periods, and by on-peak and off-peak periods within  
574 those seasons as applicable. The top portion of Table No. 13 is the resulting BGS  
575 class load-weighted seasonal and/or TOD per unit costs and total system average  
576 load-weighted per unit cost of the inclusion of the transmission, generation  
577 capacity, and ancillary services costs to the energy-only costs shown in Table No.  
578 9. These seasonal and time differentiated per unit costs become the numerator in  
579 the formulas that determine the multiplicative ratios in Table No. 14. Based on  
580 the assumptions utilized in the above tables, the bottom portion of this table  
581 shows, for each BGS service classification the total estimated "all-in" BGS costs  
582 to be recovered on an energy-only basis and the average per unit costs as  
583 measured at the customer meters or the bulk system.

584 **Q. Please explain Table No. 14 of Resp. Exhibit 5.3.**

585 A. This table is one of the most critical tables in the Prism. The upper portion of the  
586 table summarizes, for each BGS auction product, the total estimated costs of the  
587 BGS rate classes based on the inputs utilized in Tables 1-13 for each class and the  
588 resulting average “all-in” per unit cost measured at the customer meters and the  
589 bulk system. The middle and lower portions of this table is the resulting ratio  
590 (multiplicative factors) of each of the individual rate element cost components  
591 from Table No. 13, for each BGS rate class, to the overall all-in costs as measured  
592 at the bulk system from the top portion of this table.

593 **Q. Please explain Table No. 15 of Resp. Exhibit 5.3.**

594 A. Table No. 15 shows the calculation of the total BGS costs, by season utilizing the  
595 seasonal customer usage from Table No. 3, adjusted for losses from Table No. 6,  
596 and the all-in unit costs from Table No. 13. The lower portion of this table  
597 indicates the relative percentage of total costs by season and the overall average  
598 all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall  
599 average seasonal costs to the overall total costs from Table No. 14 are the  
600 seasonal payment ratios upon which seasonal payments to the winning bidders are  
601 based

602 **Q. Please explain Table No. 16 of Resp. Exhibit 5.3.**

603 A. Table No. 16 contains a reconciliation of the revenues recovered by application of  
604 the rate multipliers from Table No. 14 to the payment to suppliers based on the  
605 seasonal payment factors from Table No. 15 and is used as a check of the Prism’s  
606 operation.

607   **Q.    What is the next step in translating the single winning bid price from the**  
608       **auction processes into BGS rates for the respective customer groups?**

609    A.    The next step in the process is the determination of the Ameren Companies’  
610       average capacity and energy supply cost. The average cost is the weighted  
611       average price that would be paid to BGS suppliers accounting for seasonal  
612       payment factors and BGS sales volume by season. As discussed in Mr.  
613       Blessing’s direct testimony, we are proposing, for the under 1MW (< 1,000 KW)  
614       customers, that the auction tranches have a three year term with 1/3 of the  
615       tranches expiring and being re-auctioned annually. The initial auction will have a  
616       17-month, a 29-month, and a 41-month product. There will be a one year product  
617       for the large customer class BGS-4, except in the initial auction for which there  
618       will be a 17month product. Each year the auctions will be repeated so that the  
619       Companies can replace the expiring tranches from prior auctions. The clearing  
620       price for each of the three products (the current auction results with prior auction  
621       results) will be multiplied by the Companies’ seasonal payment factors (those  
622       from current auction and those from prior auctions). These seasonal prices for  
623       each product will then be weighted by the associated number of tranches and  
624       seasonal sales volumes to determine the weighted average cost applicable to BGS  
625       load.

626       For example, assume that for the initial auction for the under 1MW customers: (1)  
627       the winning bid prices for the 17, 29 and 41-month products are \$40.00, \$41.00  
628       and \$42.00 per MWh, respectively; (2) there are 60 total tranches bid, 20 tranches  
629       per product; (3) the seasonal payment factors per the initial Prism are 1.200 and

630 0.900 for the summer and non-summer respectively; (4) forecast BGS class MWh  
631 at the bulk system are 9,000,000 for the summer period and 14,000,000 for the  
632 non-summer period. The resulting weighted average bid price would be

$$\$40 \times 20/60 \times 1.2 \times 9,000,000 = \$144,000,000$$

$$\$41 \times 20/60 \times 1.2 \times 9,000,000 = \$147,600,000$$

$$\$42 \times 20/60 \times 1.2 \times 9,000,000 = \underline{\$151,200,000}$$

$$\$442,800,000$$

$$\$40 \times 20/60 \times 0.9 \times 14,000,000 = \$168,000,000$$

$$\$41 \times 20/60 \times 0.9 \times 14,000,000 = \$172,200,000$$

$$\$42 \times 20/60 \times 0.9 \times 14,000,000 = \underline{\$176,400,000}$$

$$\underline{\$516,600,000}$$

$$\$959,400,000$$

$$\$959,400,000 \div 9,000,000 + 14,000,000 = \underline{\$41.71} \text{ per MWh}$$

633 Continuing on, the following auction for the next BGS rate period will be 30  
634 tranches for a 36-month product, at a winning bid price of \$45.00 per MWh. The  
635 previous 17-month product is finished and there are 12 and 24 months remaining  
636 on the previous auction's 29 and 41-month products respectively. Assume: (1)  
637 the seasonal payment factors for the second auction per the Prism are 1.150 and  
638 0.8750 for the summer and non-summer respectively and (2) BGS class MWh at  
639 the bulk system are 10,000,000 for the summer period and 15,000,000 for the  
640 non-summer period. The resulting weighted average bid price for the next BGS  
641 rate period would be:

$$\$41 \times 20/60 \times 1.20 \times 10,000,000 = \$164,000,000$$

$$\$42 \times 20/60 \times 1.20 \times 10,000,000 = \$168,000,000$$

$$\$45 \times 20/60 \times 1.15 \times 10,000,000 = \underline{\$172,500,000}$$

\$504,500,000

$$\$41 \times 20/60 \times 0.900 \times 15,000,000 = \$184,500,000$$

$$\$42 \times 20/60 \times 0.900 \times 15,000,000 = \$189,000,000$$

$$\$45 \times 20/60 \times 0.875 \times 15,000,000 = \underline{\$196,875,000}$$

\$570,375,000

\$1,074,875,000

642 The new weighted average bid price that would be applicable to the next BGS rate  
643 period would then be:

$$\$1,074,875,000 \div 10,000,000 + 15,000,000 = \underline{\$43.00} \text{ per MWh.}$$

644 This process would continue annually as the 12-month product would terminate  
645 and a new 36-month product would be auctioned.

646 The final step in the process is converting this resulting annual weighted average  
647 price into retail BGS rate values for the BGS rate period. This is accomplished by  
648 multiplying the weighted average bid price by the applicable rate multiplicative  
649 factors as determined by the Prism in Table No. 14.

650 For illustrative purposes, I have attached as Resp. Exhibit 5.5 a schematic  
651 or pictorial of the Prism, showing the inputs and other factors as described that  
652 result in the final price.

653 **Q. Do the Ameren Companies envision the outputs of the Prism being used for**  
654 **other than rate development?**

655 A. Yes. The BGS pricing spreadsheets are also intended to provide bidders with an  
656 easy to use tool that can translate auction prices for each term into retail BGS  
657 rates. Bidders can enter into the spreadsheet auction prices for the Companies' 3-

658 year and 1-year tranches, click on a calculate box and be able to view the BGS  
659 rates that would result if the auction were to clear at the entered price levels. BGS  
660 prices may be important to bidders for the purpose of assessing the likelihood and  
661 degree of migration to and from BGS rates.

662 It is contemplated that bidders may use these spreadsheets in two ways. First, in  
663 preparation for the auction, bidders can examine a wide variety of scenarios of  
664 potential auction clearing prices and analyze the retail rates that result from those  
665 scenarios. These analyses can be used to examine how potential migration from a  
666 given set of retail rates may affect the bidder's valuation of the auction  
667 opportunity. Second, as the auction is in progress, bidders will be able to enter  
668 going prices and update their analysis of potential migration and the auction  
669 opportunity. Also, as discussed above, Table No. 15 provides bidders with the  
670 seasonal factors for payments to bidders.

671 **Q. Should one expect that billings generated under rates from the above-**  
672 **referenced prism achieve Ameren's goal of precisely recovering all costs**  
673 **associated with the procurement of said fixed power?**

674 A. No. The decomposition of the single winning auction prices across several rate  
675 class and pricing periods based on predicted load characteristics and estimated  
676 losses, along with seasonal payment factors for remittance of payments to  
677 successful bidders, will result in under or over-collection of power costs. As a  
678 result, the proposed BGS Riders "point to" the previously mentioned Market  
679 Value Rider -Rider MV (Resp. Ex. 4.1).



680 **Q. Please explain.**

681 A. As discussed in Mr. Mill's direct testimony, Rider MV contains, among other  
682 items, the process for translating winning bid prices into BGS rates and an  
683 MVAF, which is an adjustment mechanism to synchronize BGS power supply  
684 costs to billed revenue. Mr. Mill provides additional detail on the rationale and  
685 the mechanics of the MVAF.

686 **IV. RIDER RTP – REAL TIME PRICING DISCUSSION**

687 **Q. Mr. Cooper, please discuss Ameren's proposed RTP offering to customers**  
688 **with individual demands of greater than 1,000 kilowatts.**

689 A. The proposed Rider RTP-L contains provisions for the availability of RTP to all  
690 customers with individual demands equal to or greater than 1,000 kilowatts (>  
691 1MW). Additionally, we have designated RTP as the default power service for  
692 customers who either: (1) do not opt for BGS or RES service during the open  
693 enrollment period described in the testimony of Mr. Blessing or (2) lose RES  
694 supply for any reason.

695 **Q. Please discuss the pricing of power under Rider RTP-L.**

696 A. All energy purchased under Rider RTP-L will be priced based on provisions of  
697 the RTP-L bid contracts. These contracts contain three components for RTP-L  
698 service: (1) Energy at MISO Locational Marginal Hourly Prices ("LMPs") that  
699 vary by Ameren control area designation; (2) an energy based Rider D - Default  
700 Service Supply Availability Charge; and (3) a capacity based hourly demand  
701 charge. The proposed Rider MV contains the provisions for the pricing of these  
702 components. Of course, all of these charges will be adjusted for system losses.

703 **Q. Earlier you mentioned Ameren's desire to have one set of prices for power**  
704 **and energy across its entire Footprint. Why are you proposing varying RTP**  
705 **related LMPs depending on which control area of Ameren's a customer is**  
706 **located?**

707 A. Current MISO provisions do not allow the Ameren control areas to be treated as  
708 one "virtual" control area for LMP purposes. As a result, it is not possible to  
709 provide a single LMP for any hour that would be representative of the comparable  
710 hour LMP for each of Ameren's three control areas. Therefore, RTP customers  
711 will be subject to LMPs based on the control area of which they are located.  
712 Differences in LMPs among the Ameren control areas are primarily tied to  
713 transmission congestion costs and are expected to be minimal. Additionally, we  
714 are optimistic that in time MISO will treat the control areas as one and subsequent  
715 RTP related LMPs would be same for all of the Ameren Companies.

716 **Q. Are any of the above mentioned charges for Rider RTP-L customers**  
717 **applicable to Rider RTP-L eligible customers with RES service?**

718 A. Yes. Pursuant to the RTP-L bid contracts, the Companies are proposing that all  
719 Rider RTP-L eligible customers with RES service be subject to the non-  
720 bypassable Rider D.

721 **Q. Please explain.**

722 A. RTP-L power and supply bidders have included a Rider D charge or component  
723 on a cents per kilowatt hour basis for all Rider-RTP-L load and all Rider RTP-L  
724 eligible load with RES service. As stated earlier, we propose to bill this charge on

725 a cents per kilowatt hour basis, as adjusted for losses, to all Rider RTP-L  
726 customers and Rider RTP-L eligible customers with RES power service.

727 **Q. Please discuss the proposed RTP offering to customers with individual**  
728 **demands of less than 1,000 kilowatts (< 1 MW).**

729 A. The proposed Rider RTP contains provisions for the availability of RTP to all  
730 customers with individual demands of less than 1,000 kilowatts. Unlike terms for  
731 customers with individual demands of 1,000 kilowatts or greater, the Companies  
732 have designated BGS the default power service for customers with individual  
733 demands of less than 1,000 kilowatts.

734 **Q. Please discuss the pricing of power under Rider RTP.**

735 A. All energy purchased under Rider RTP will be priced under Rider MV.  
736 Essentially, small customers opting for this service will receive “virtual” or  
737 equivalent billing under proposed Rider RTP-L, as described above, excluding the  
738 Rider D charge.

739 **Q. Please elaborate.**

740 A. As discussed in the testimony of Mr. Blessing, the Companies will not request  
741 bids for RTP power for customers with individual demands of less than 1,000  
742 kilowatts. However, the Companies propose that these customers be billed as if  
743 they were served under Rider RTP-L without the imposition of Rider D charges  
744 for customers within this category who do opt for RES service. Therefore, Rider  
745 D charges will only be applicable to customers opting for RTP service. The  
746 rationale for omitting Rider D charges for RES-served customers in this category  
747 lies in the defaulting of these customers to BGS versus RTP. The bid price for

748 BGS for all customers in this class should include a component for the defaulting  
749 of this service to BGS; the inclusion of Rider D on RES served load in this  
750 category would suggest a “double counting” of sorts.

751 V. **SWITCHING RULES DISCUSSION**

752 Q. **Will customers eligible for the various BGS service offerings be subject to**  
753 **switching rules?**

754 A. Yes. There is a direct correlation between auction bid price and switching and  
755 minimum stay requirements for customers with choices between utility provided  
756 power and service from a RES. Typically, the greater the load uncertainty, the  
757 greater the probability that suppliers will be compelled to add larger risk  
758 premiums to offset risks. However, there are concerns that the existence of  
759 switching and minimum stay rules may impede the development of the power  
760 market. The following switching/minimum stay rules should strike a reasonable  
761 balance between the goals of supporting the development of a robust power  
762 market and, at the same time, obtaining the lowest possible market prices for  
763 customers. The proposed Rider MV tariffs contain the applicable switching rules.

764 VI. **TRANSMISSION SERVICE DISCUSSION**

765 Q. **You have now discussed the proposed post-2006 power service offerings.**  
766 **Please discuss the Companies’ plan for Transmission Service offerings.**

767 A. The Companies plan to file a Transmission Service Rider – Rider TS with their  
768 next Delivery Service case. This rider will contain all provisions for the  
769 providing of transmission service to customers opting for power service from the  
770 Companies’ post-2006 and will provide for full recovery of all costs, fees, and

771 charges for transmission and related services not otherwise recovered under the  
772 BGS or RTP riders. This rider is not expected to apply to customers taking  
773 service from a RES.

774 **VII. OTHER POWER SUPPLY DISCUSSION**

775 **Q. What are you proposing for power sales to customers with non-emergency**  
776 **self-generation that operates in parallel with the Ameren Companies?**

777 A. We are proposing that customers with self-generation capacity of less than five  
778 (5) megawatts be offered power service under either Rider BGS or Rider RTP.  
779 This proposal provides customers with small to medium sized self generation  
780 units the flexibility of selecting applicable BGS or RTP power service  
781 simultaneous with full flexibility in operating their generators in a manner  
782 consistent with their internal economics. Based on initial customer survey  
783 intelligence, it is anticipated that the aggregate capacity of self generation in this  
784 category represents approximately five (5) percent of total non-emergency  
785 customer self generation installed on the Ameren Companies.

786 **Q. What are you proposing for power sales to customers with non-emergency**  
787 **self-generation equal to or greater than five (5) megawatts that operates in**  
788 **parallel with the Ameren Companies?**

789 A. We are proposing that customers with self-generation capacity equal to or greater  
790 than five (5) megawatts be offered a “hybrid” of power service under Rider BGS  
791 and Rider RTP or, in the alternative RTP, only.

792 **Q. Please explain the proposed hybrid Rider BGS and Rider RTP power**  
793 **offering for these customers.**

794 A. Customers with non-emergency self-generation at these levels tend to be very  
795 sophisticated energy managers. In some cases, these customers utilize excess  
796 steam from product process operations to run in house generator sets. We are  
797 proposing that customers in this category be subject to a hybrid billing that: 1)  
798 adequately reflects the costs of providing power service to their unique  
799 operations, 2) provides proper price incentives with regard to whether self  
800 installed generation output is more economic than market based RTP, and 3)  
801 minimizes the opportunity for these customers to place low load factor load on the  
802 system at prices that don't reflect actual market prices.

803 **Q. Please elaborate.**

804 A. First, customers in the above category will be required to pay the Ameren  
805 Companies for the installation of metering or install, at their own costs, acceptable  
806 metering for measuring the output of their generators. Additionally, standard  
807 metering for the billing of the Companies' DS, BGS, and RTP services will be  
808 required. The hybrid proposal will bill all Company metered power usage in  
809 excess of that that could be hypothetically served by the customer's self  
810 generation at a one-hundred percent capacity factor under the applicable Rider  
811 BGS fixed price product. However, any Company metered power usage metered  
812 during intervals where the customer's generator is operating at less than one-  
813 percent capacity, will be billed under the applicable RTP. While this approach is  
814 somewhat complex, billing can be easily accomplished by a comparison of the

815 interval meter reads between the customer's generation meter and the customer's  
816 DS, BGS, and RTP power meter. Additionally, this hybrid billing addresses the  
817 three concerns mentioned above and is just and reasonable. Based on initial  
818 customer survey intelligence, it is anticipated that the aggregate capacity of self  
819 generation in this category represents approximately ninety-five percent of total  
820 non-emergency customer self generation installed on the Ameren Companies'  
821 system. Additionally, this hybrid billing proposal provides a proper balance  
822 between the customer's desire to economically operate self generation and our  
823 desire to have power prices that reflect cost causation and equitable cost recovery  
824 principles.

825 **Q. What are you proposing for power and energy sales to customers desiring**  
826 **power service from the Ameren Companies to supplement or augment power**  
827 **being provided by an ARES?**

828 A. We are proposing that customers desiring power and energy from Ameren to  
829 supplement or augment power provided from an ARES be served under the  
830 applicable RTP offering. The application of the RTP offering for supplementing  
831 or augmenting power and energy provided by a ARES is reasonable considering a  
832 primary criterion (i.e., homogeneous load or usage characteristics) in establishing  
833 rate design for the Company's fixed price offering. A customer obtaining power  
834 and energy service from a RES may be homogeneous with the other ARES or  
835 Company customers from a load perspective, however, its use of power and  
836 energy service from an ARES versus that served by one of the Companies could  
837 vary significantly. For example, if we were to offer the fixed price product to

838 these participants in the market, one would expect that, wherever possible, they  
839 will place load swings or peaks during periods of high costs on our system at a  
840 fixed price, while base loading on the ARES at a lower per unit price. The use of  
841 RTP for power and energy service required to supplement or augment ARES  
842 service minimizes the likelihood of these customers behaving in this manner,  
843 prevents subsidies to the detriment of our fixed price customer groups, and sends  
844 a better or more proper price signal. Thus, the use of RTP for this service is just  
845 and reasonable, and also promotes the development of an efficient market for  
846 power and energy.

847 **Q. Earlier you mentioned that the Ameren Companies would be filing DS cases**  
848 **for new rates to become effective prior to the effective date of the post-2006**  
849 **BGS offerings. Please discuss the basic objectives of your delivery services**  
850 **filings as they may relate to BGS.**

851 A. The objectives of the DS filings are as follows: (1) complete recovery of the  
852 Ameren Companies' DS related revenue requirements; (2) alignment of DS  
853 classes with BGS/RTP classes; (3) class revenue requirements and rate design that  
854 reflect cost causation and equitable cost recovery principles; (4) competitively  
855 neutral DS rates (i.e., rates for DS should be the same whether customer opts for  
856 virtual bundled service from the Ameren Companies, or takes DS from the  
857 Companies with power from an ARES. Achievement of these DS objectives will  
858 assist in promoting a robust retail market for power in Illinois, promote ease of  
859 customer and employee understanding of our rates and tariffs, and provide our  
860 shareholders with a reasonable rate of return. As a result, all stakeholders benefit.



861 **Q. Have you prepared an exhibit that maps the Ameren Companies' existing**  
862 **bundled retail electric Service Classifications to expected post-2006 DS, TS,**  
863 **and BGS/RTP applications for the continuation of "virtual" bundled service?**

864 A. Yes. Resp. Exhibit 5.4 contains this mapping for the Ameren Companies'  
865 classifications.

866 **Q. Will customers defaulted to BGS-1, 2, and 3 on January 2, 2007, be required**  
867 **to remain on such for an entire year?**

868 A. No, we recognize that despite the efforts of all the parties in this process to  
869 educate consumers prior to January 2, 2007, there will still be some confusion,  
870 especially with smaller customers. As a result, all customers initially defaulted to  
871 BGS 1, 2, or 3 may switch to any other available BGS rates at any time subject  
872 only to DASR requirements.

873 **Q. Please discuss your proposed BGS treatment for new connections/customers**  
874 **post-2006.**

875 A. All "new" (i.e., customers served from new distribution extensions or successor  
876 customers) customers will be given the option of either BGS "fixed" price or RTP  
877 service, if they request power service from the Ameren Companies.

878 **Q. Does this conclude your direct testimony?**

879 A. Yes, it does.